Order, NIEP and CCW maintain that the price mitigation directive in the July 25 Order would require a review of QFs' costs, which is contrary to Order No. 69 in which the Commission rejected cost-of-service regulation of QFs. They also argue that it would be contrary to PURPA, 16 U.S.C. § 824a-3. They assert that although a QF may voluntarily accept some rate other than its avoided cost, if the QF is compelled to sell rather than voluntarily offer, the QF is entitled to full avoided costs.

CAC reasserts the same arguments it made on rehearing of the April 25 Order.

Commission Response

As part of the Commission's efforts to alleviate the severe electric energy shortages facing California and the West, the Commission took a number of actions, including several related to QFs. Among them, the Commission granted temporary waiver of the technical regulations relating to QF status through April 30, 2002.[110] The waivers were intended to facilitate the sale of "excess QF power."[111] Sales pursuant to the waivers were to be pursuant to negotiated bilateral contracts[112] and were to be made

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[110] See December QF Order at 61,773; December 15 Order at 62,018; and Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, 94 FERC ¶ 61,272 at 61,970-71 (2001) (March 14 Order); Further Order Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, 95 FERC ¶ 61,225 (2001).

[111] "Excess QF power" was defined as power above what has been historically sold from a facility to the purchasing utility. A facility's seasonal average output during the two most recent years of operation will define historical output. See December QF Order. See also Order Granting Motions for Emergency Relief in Part and Deferring Action on Other Aspects of Motions and Proposed Order Under Section 201(d) Directing Interconnections with Qualifying Facilities and Establishing Further Procedures, 95 FERC ¶ 61,226 at 61,782-83 (2001) (May 16 QF Order).

[112] December QF Order at 61,773.

if consistent with the contractual obligations to purchasing electric utilities[113] and to thermal hosts.[114] Our July 19 and July 25 Orders were issued in this context.

There is no merit to the QF-related arguments made on rehearing. First, as to the arguments that QFs are being compelled to make sales inconsistent with their obligations to either purchasers of their electric or thermal output, the July 19 Order explicitly stated that the Commission was not ordering QFs to make sales that were inconsistent with contractual obligations, whether the contractual obligations were to electric utilities or to thermal hosts. Thus, the order presents no conflict with delivery obligations either to utilities or thermal hosts. We will, however, modify the previous waivers of the Commission's technical requirements (18 C.F.R. §§ 292.204 and 292.205 (2001)) to extend the waivers from April 30, 2002, until the end of that calendar year, i.e., until December 31, 2002. We do this because, under our regulations, compliance with the technical requirements for QF status is measured on a calendar year basis, and the extension of the waiver will thus make the waiver consistent with how compliance with our regulations is measured. The extension removes any doubt that a QF, which makes sales prior to April 30, 2002 pursuant to the waiver already granted, will maintain QF status without having to alter operations to bring their operations into compliance with the technical requirements for QF status for the calendar year.

Regarding the argument that our orders are inconsistent with the exemption granted to QFs from certain requirements of the FPA, as we noted in the June 19 Order, QFs are public utilities that are subject to the Commission's jurisdiction. Pursuant to PURPA, they have been exempted from many of the requirements of the FPA and other federal and state legislation. When we imposed the must-offer requirement, we chose not to extend the exemptions already granted to QFs to this new requirement and thus did not exempt the QFs from the must-offer requirement. We did this because of the need for uniformity among sellers and the great need for additional power supplies. No arguments have been raised on rehearing that would cause us to reach a different result.

Regarding arguments that our orders will compel sales at prices inconsistent with PURPA, we disagree. QFs that operate under this regimen will not be compelled to make sales inconsistent with the pricing provisions of PURPA. The QFs' primary sales

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[113]May 16 QF Order at 61,788 & n.18 (where a purchasing utility and a QF do not agree that there is "excess QF capacity" the issue is to be determined by a state court and may require permission of the bankruptcy court).

[114]June 19 Order at 62,553 (the must-offer requirement applies to energy that is available from generation that is not already contractually committed and would not violate its contractual obligation to its thermal host).

remain sales pursuant to contracts with purchasing utilities with either negotiated rates or rates set by a state commission. Those rates are consistent with our regulations implementing PURPA.[115] The vast majority of the remaining sales will take place pursuant to negotiated bilateral contracts, which are also consistent with the Commission's regulations under PURPA.[116] Any remaining sale (where a QF, which was not relying on the waivers to make a sale and thus was not required to enter into a bilateral contract to make such sales, but was contractually free to make a sale and thus subject to the must-offer requirement) would take place at the price the purchasing utilities are paying other sellers for similarly available electric energy (i.e., the purchasing utilities' avoided cost); those sales would also be consistent with the Commission's regulations under PURPA.[117]

c. Applicability to Marketers

i. June 19 Order

On rehearing of the June 19 Order, marketers strongly oppose the requirement that they be price takers. For example, Enron argues that precluding cost justification filings based on marketers' own costs is arbitrary, potentially confiscatory and unsound policy and will prevent marketers from participating in WSCC spot markets, thereby degrading liquidity and reliability, and leading to increased costs for the consumer.[118]

Allegheny contends on rehearing that the mitigation plan prevents marketers from bidding and prohibits reasonably incurred costs from being included in such justification;[119] that the June 19 Order has a discriminatory impact on power

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[115] See 18 C.F.R. §§ 292.301- 292.304 (2001).

[116] See 18 C.F.R. § 292.301 (b) (2001).

[117] See 18 C.F.R. § 292.101(b)(6) (Avoided costs means the incremental costs to an electric utility of electric energy . . . but for the purchase from the qualifying facility or qualifying facilities, such utility would . . . purchase from another source).

[118] See also Requests for Rehearing of Idacorp, Mirant, IEP, PPL, and Sempra Trading.

[119] See also Requests for Rehearing of Avista Energy, BP Energy, El Paso.

marketers;[120] and that there is no evidentiary support for making all marketers become price takers in spot markets and allowing only generators to submit cost support.[121] El Paso asserts that this requirement is inappropriate where the Commission did not find evidence that power marketers had or exercised market power. BP Energy contends on rehearing that if a marketer purchases power in a bilateral transaction that is not a spot market transaction, then the purchase price is not mitigated but the sales price is mitigated. EPSA contends that the requirement that marketers be price takers disregards the benefits power marketers provide.

Allegheny and Avista Energy request clarification of the June 19 Order that any entity that owns or controls generation and engages in marketing through a portfolio of physical and contractual resources should be governed by the same rules applicable to generators.[122] Calpine seeks clarification that marketing affiliates of generators are not price takers and that marketer-to-marketer transactions (i.e., those transactions not involving an LSE or the ISO, the costs of which may be passed through to ratepayers) are exempt from the requirement to be price takers.

Duke requests clarification that marketers as price takers can receive their bid price up to the mitigated Market Clearing Prices,[123] stating that the ISO has taken the view that marketers are not only prohibited from bidding above the mitigated Market Clearing Prices but are also prohibited from setting the market clearing price when the market clears at a level below the mitigated Market Clearing Prices. Mirant requests on rehearing of the June 19 Order that the Commission allow marketers and other sellers to justify prices above the mitigated price based on the cost of purchased power, subject to Commission oversight for potential affiliate abuse.

El Paso states that the June 19 Order creates uncertainty as to whether or not marketers whose bids during reserve deficiency hours are subsequently determined to be above the mitigated reserve deficiency MCP will be required to consummate the sale at the reduced price.

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[120] See also Request for Rehearing of Avista Energy.

[121] See also Request for Rehearing of El Paso.

[122] See also Request for Rehearing of Calpine.

[123] The term "mitigated Market Clearing Prices" as used in this order includes the mitigated market clearing price established for both reserve deficiency and non-reserve deficiency periods.

Enron requests clarification that marketers that fulfill functions normally provided by a Scheduling Coordinator for a specific generator, or otherwise act as the generator's agent, or as a toller,[124] will not be treated as marketers and should be allowed to file justification to recover costs incurred in excess of the mitigated Market Clearing Prices.

Southern Cities requests clarification that LSEs who resell excess energy under long-term contracts entered into prior to June 19, 2001 will not be treated as marketers and therefore will not be required to sell this excess energy at prices less than their costs to acquire such energy.

PG&E requests clarification that marketers are price takers in all hours in which they sell into the spot market. PG&E also requests clarification that hydroelectric generation, like sales by marketers, will be price takers in all hours. According to PG&E, the June 19 Order provides that marketers must bid as price takers, but then provides that marketers cannot bid higher than the mitigated Market Clearing Prices. PG&E requests that the Commission fix this ambiguity so that sellers with higher cost units will still be able to bid or demand prices that reflect their running costs, but marketers will not be able to increase those prices further.

Commission Response

To prevent the use of megawatt laundering[125] as a strategy for evading potential mitigation, the June 19 Order prohibited marketers from bidding a price higher than the mitigated reserve deficiency MCP. Thus, marketers were required to be price takers. The Commission reasoned that "[t]his will still provide marketers with an opportunity to earn a reasonable return on purchased energy, since the mitigated price is established by the marginal costs of the last unit dispatched and this price will be above the costs of the generators from which the marketers obtain their portfolio of energy."[126] Due to their multi-purpose limitations, hydroelectric generators are not subject to the must-offer

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[124]Enron defines tollers as entities that provide the fuel to a generator in exchange for some or all of the power output from the generator.

[125]As explained in the June 19 Order, megawatt laundering occurs where a generator sells power to an out-of-state marketer who then reimports that power to avoid a mitigated price.

[126]June 19 Order at 62,564.

obligation.[127]. Hydroelectric generators, however, are price takers during the hours in which they choose to participate in the spot market.

The Commission now clarifies that the mechanism to make marketers price takers is to require marketers that do not resell in other bilateral markets and choose to participate in the real-time spot market to bid at $0/MWh, not at the mitigated Market Clearing Prices. The marketer will then be paid the market clearing price, up to the mitigated Market Clearing Prices. The same mechanism will apply to LSEs that choose to participate in the real-time spot markets by reselling excess energy that they themselves did not generate.

Due to the difficulty of tracing energy back to the generating source to determine the heat rate and gas prices of the source, especially if multiple sources are used, the June 19 Order precluded marketers from justifying costs above the mitigated reserve deficiency MCP. This restriction was imposed to prevent marketers from circumventing the Commission's price mitigation measures. The Commission will continue to preclude marketers from submitting justification for transactions above the mitigated Market Clearing Prices.

The Commission rejects marketers' contention that requiring them to be price takers will prevent them from recovering reasonably incurred costs. Under the mitigation plan, marketers are not subject to the must-offer requirement and therefore are not required to bid into the real-time spot markets if they believe they will not recover their purchased power or other costs. The real-time market is the last opportunity to resell energy and the only alternative is to allow the resource to be unused with no revenue recovery.

The Commission denies clarification that marketers that own or control generation and engage in marketing through a portfolio of resources, or that perform scheduling or tolling functions on behalf of generators, will be treated as generators; they must be price takers. By contrast, entities that are able to trace a transaction to a specific generating unit will be treated as generators. With respect toCalpine's request for clarification, the Commission will require marketing affiliates of generators to be price takers. Furthermore, marketer-to-marketer transactions in the bilateral spot market are subject to price mitigation and marketers selling outside of the ISO's single price auction will receive the price up to the mitigated Market Clearing Price.

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[127]See April 26 Order at 61,357.

We deny Southern Cities' request for clarification that LSEs that resell excess energy under long-term contracts entered into prior to June 19, 2001 into the real-time spot markets will not be treated as marketers. LSEs that choose to resell excess energy acquired under long-term contracts into the real-time spot markets will be price takers.

We will not address the argument that sellers of hydroelectric power should be permitted to recover opportunity costs, because hydroelectric power is not subject to the must-offer requirement. If these sellers do not believe that they will recover their costs during any particular time period, because they prefer to save their resources to maximize the value of the hydroelectric power, they need not offer their power for sale. However, if they do offer their power for spot market sales, they are subject to price mitigation.

ii. July 25 Order

Marketers object to the holding in the July 25 Order that they, as price takers, may not justify transaction prices above the mitigated Market Clearing Prices. Mirant asserts that, applied on a retroactive basis, the prohibition is illogical (punishing marketers for behavior that enhances market liquidity), potentially confiscatory, and unjustifiably discriminatory as between generators and marketers. Portland General also objects to the discrimination that results from requiring non-generators to "take" a fictional price while permitting other market participants to justify their actual price.

On rehearing of the July 25 Order, EPSA raises marketers' concerns that ordering refunds from them based on a Proxy Price set by a generator is inappropriate, noting that marketers' costs have nothing to do with the operating costs of particular generating units. Because marketers manage their operations on a portfolio basis, EPSA argues that it is not reasonable to consider each specific transaction when determining whether a marketer made sales above prices that a competitive market would yield. Finally, EPSA asserts that, although marketers may be able to change their future decisions based on the Commission directives, "power markets do not provide an opportunity to retroactively change completed transactions."[128]

The Marketer Group contends on rehearing of the July 25 Order that the Commission erred when it refused to consider evidence that refunds of marketers' charges that exceed generators' operating costs will yield rates that are confiscatory. The Marketer Group continues that, while marketers accept the risk of not making a profit for certain transactions, "they should not be required to accept the risk of unlawful

[128]Request for Rehearing of EPSA at 29.

regulatory confiscation after-the-fact."[129] Avista does not dispute the Commission's imposition of refund liability on marketers, but contends that the Commission erred in applying a Proxy Price developed for generators that failed to account for the "unique cost issues" facing power marketers.

The Marketer Group also challenges the failure of the Commission in the July 25 Order to consider the characteristics of sellers of hydroelectric power, i.e., not accounting for the opportunity costs involved in hydro generation. The Marketer Group explains that hydroelectric generators offer their resources at the expected summer price, and asserts that marketers with hydro-based portfolios will follow the same pricing strategy.

Commission Response

While it is true that marketers have not yet been provided an opportunity to justify bids above the mitigated Market Clearing Prices for transactions that occurred during the refund period, or to submit evidence that the refunds are confiscatory, this is true for all sellers. Thus, the policy does not discriminate against marketers. The July 25 Order established an evidentiary hearing limited to the collection of data needed to apply the refund methodology. During the hearing, parties do not have an opportunity to submit additional evidence. However, as explained further below,[130] the Commission will provide an opportunity after the conclusion of the refund hearing for marketers to submit cost evidence on the impact of the refund methodology on their overall revenues over the refund period. For the Commission to consider any adjustments, marketers will have to demonstrate that the refund methodology results in a total revenue shortfall for all jurisdictional transactions during the refund period. The Commission will consider such submissions in light of the regulatory principle that sellers are guaranteed only an opportunity to make a profit. To the extent we stated in the July 25 Order that we would not allow such a showing regarding sellers' purchased power costs,[131] we grant rehearing. We will also allow sellers of hydroelectric power to demonstrate the impact of the refund methodology.

This modification should satisfy marketers' concerns. Marketers are not being treated differently from generators. They will have an opportunity to offer evidence that

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[129] Request for Rehearing of Marketer Group at 27.

[130] See infra, section F.

[131] See July 25 Order at 61,518.

their revenues are less than their total costs.[132] Demonstrations related to those reselling purchased power or selling hydroelectric power must also show the impact on all transactions from all sources during the refund period.

d. Applicability to DWR and OOM Transactions

Several parties argue that DWR's spot market purchases should be included in refund determinations.[133] They argue that DWR's spot market purchases were made in the same dysfunctional market in which ISO out-of-market (OOM) purchases were made and like ISO OOM purchases were made at extremely high prices that are unjust and unreasonable. Since the Commission determined that ISO OOM purchases are subject to refund, they argue that there is no rational basis to treat DWR's purchases differently. Further, they contend that DWR did not voluntarily enter into transactions outside the ISO because the Commission terminated the PX Tariff and imposed a penalty on underscheduled load and sellers refused to offer supply through the ISO's real-time market. Thus, they assert that the sellers and DWR had unequal bargaining positions. They argue that it was unlawful for the Commission to find that an imbalance of supply and demand provides sellers with market power and attempt to force customers to purchase 95 percent of their electricity in the forward market[134] – while refusing to mitigate sales in the forward market or to provide refunds for such sales when they are clearly unjust and unreasonable.

With regard to DWR's access to the ISO's control room, California Parties contend that, when DWR became the only creditworthy California purchaser, it was not unreasonable for DWR to need and obtain access to the ISO's trading floor. Further, they assert that this proceeding concerns rates charged by sellers, but the ISO and DWR are customers and would be entitled to just and reasonable rates even if the Commission believed that they had engaged in improper conduct.

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[132]In keeping with EPSA's comment that it is not reasonable to consider each specific transaction, the Commission will consider the impact on a marketers' entire portfolio of transactions over the duration of the refund period.

[133]See, e.g., Requests for Rehearing of California Parties, ISO, PG&E, Oversight Board.

[134]Forward markets are defined as markets with transactions with a future delivery that are entered into more than 24 hours before commencement of service. See June 19 Order at 62,546, n.9.

PG&E argues that this proceeding has not been limited to the centralized ISO and PX markets. Rather, PG&E argues that the Commission has been addressing all transactions in California wholesale markets.[135]

Puget/Avista object to the Commission making ISO OOM spot market purchases subject to refund because the decision is not supported by the record and is inconsistent with the treatment of DWR bilateral transactions. Others argue that these sales should not be subject to refund because OOM sales do not involve sales into either the ISO's or PX's markets; rather, they are bilateral transactions that arise out of a separate authorization under the ISO's tariff for the purpose of assuring grid reliability.[136] Portland General also points out differences between the ISO's centralized auction market, where the price is set by the highest bid dispatched, and its OOM transactions, which are freely negotiated. Portland General asserts that OOM transactions are much more like DWR's, which the Commission determined are not subject to refund, and states that the Commission made no specific findings that rates for OOM transactions were unjust and unreasonable.

The Marketer Group also argues that, to the extent that OOM sales were made subject to refund, it was not pursuant to the August 23 or November 1 Orders; rather, it could only have been pursuant to the April 26 Order which established a refund effective date of July 2, 2001 for all sales in the WSCC generally. Thus, the Marketer Group argues that the determination in the July 25 Order to make OOM purchases subject to the October 2, 2000 refund effective date violated section 206 of the FPA.

On August 30, 2001, as corrected on November 13, 2001, CARE filed a motion seeking an order canceling or suspending DWR's long-term energy contracts and associated IOU rate schedules on the basis that they were not properly filed by DWR pursuant to the FPA. CARE bases its motion on the contention that DWR is acting as a "designated representative" as described in 18 C.F.R. § 35.1(a), because of actions that DWR has taken before the California Commission. Mirant filed an answer in response to the motion asserting that the DWR contracts to which it is a counterparty need not have

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[135]As an example, PG&E cites the November 1 Order, 93 FERC at 61,370 ("if the Commission finds that the wholesale markets in California are unable to produce competitive, just and reasonable prices, or that market power or other individual seller conduct is exercised to produce an unjust and unreasonable rate, we may require refunds for sales made during the refund effective period.").

[136]See, e.g., Requests for Rehearing of Marketer Group, Nevada IEC/CC Washington, CAC.

been filed because Mirant, as a power marketer with no generating assets, is not required to file service agreements.

Commission Response

The Commission disagrees with the arguments for extending refund liability to include DWR transactions. DWR transactions are negotiated bilateral contracts for the procurement of energy on behalf of California IOUs, and are distinctly beyond the realm of ISO and PX centralized market operations that have been the subject of this proceeding since its inception. Whether or not DWR could have conducted its transactions through the ISO is immaterial. In addition, although some of DWR's contracts may have been in the spot market, most were not; indeed, the intent of DWR's involvement in the market was to enter into longer-term contracts. PG&E's selection of a single reference to "California wholesale markets" not specifically limited to spot markets operated by the ISO and PX ignores the dozens of other references prior to, subsequent to, and within, the November 1 Order that acknowledge the limited scope of the proceeding. For example, on the first page of the November 1 Order, the Commission indicated its finding that the California electric market structures and market rules, "in conjunction with an imbalance of supply and demand in California, have caused, and continue to have the potential to cause, unjust and unreasonable rates for short-term energy (Day-Ahead, Day-of, Ancillary Services and real-time energy sales) under certain conditions."[137] No party could reasonably have believed that the Commission intended the proceeding to be broader. As the Commission noted in the July 25 Order, if DWR or another party believes that any of its contracts are unjust and unreasonable, it may file a complaint under FPA section 206 to seek modification of those contracts, assuming the seller is a public utility.

ISO OOM transactions, on the other hand, are purchases for the purpose of maintaining reliability on the ISO-controlled grid and are necessarily purchases of short-term energy. They are contemplated in the ISO Tariff as a backstop to the ISO's auction markets. It is only when the ISO market produces insufficient resources that the ISO must resort to out of market purchases. It follows that if the price in these markets is subject to refund, then the price for the OOM transaction (which is a purchase of last resort in lieu of a market purchase) is subject to refund also. Relatively early in this proceeding, parties sought clarification that OOM transactions would be subject to the reporting and cost justification requirements of the December 15 Order,[138] and the

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[137]November 1 Order, 93 FERC at 61,349, emphasis added.

[138]See, e.g., Requests for Rehearing of the December 15 Order of ISO, PPL. See

(continued...)

Commission included OOM transactions when identifying those which were above the monthly proxy market clearing price in the March 9 Refund Order and subsequent notices. The July 25 Order did not expand the scope of the proceeding but merely clarified that the OOM transactions are within suppliers' refund liability. Thus, the appropriate refund effective date for ISO OOM transactions is October 2, 2000, the same date as for all ISO and PX spot market transactions.

In the July 25 Order, we noted the competitive advantage DWR had by virtue of its access to the ISO's control room and trading floor information as a further reason why refund liability should not attach to its transactions. We cannot agree with California Parties that DWR had any legitimate reason to position its employees in the ISO's control room.[139] California Parties fail to demonstrate why it was necessary to grant one market participant -- DWR -- preferential treatment over all other power market participants in order for the ISO to meet its obligations and responsibilities over the transmission grid. DWR is not involved in the operation of the transmission grid and does not need the same information that the ISO needs. As the Commission recently held in a separate proceeding, preferential disclosure to DWR of confidential market information is unacceptable.[140] We also disagree that DWR is merely a customer in these markets; it has an interest in recovering the costs of its purchases from end users.

With respect to CARE's motion seeking suspension of DWR's contracts, we disagree that DWR is a "designated representative" as defined in the Commission's regulations. Section 35.1(a) of the Commission's regulations states that, where two or more public utilities are parties to the same rate schedule, each one must file the rate schedule. An exception to that rule, relied on by CARE, is that "[i]n cases where two or more public utilities are required to file rate schedules . . . such public utilities may authorize a designated representative to file upon behalf of all parties if upon written request such parties have been granted Commission authorization therefor." Initially, we note that DWR's actions in proceedings before the California Commission have no

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[138](...continued)
also comments of Reliant in Docket No. EL01-23-000 at 8 (filed soon after issuance of the December 15 Order, noting that prices for OOM transactions are subject to the Commission's review under the existing price mitigation scheme).

[139]In a status report filed on October 12, 2001, in Docket No. ER01-889-000, the ISO informed the Commission that DWR no longer had access to its control room as of September 1, 2001.

[140]Reliant Energy Power Generation, Inc., et al. v. California Independent System Operator Corp., 97 FERC ¶ 61,215 (2001).

impact on its status here. More fundamentally, a discretionary arrangement between public utilities permitted by the Commission's regulations has no bearing on DWR's status. CARE presents no basis for canceling or suspending DWR's contracts. Accordingly, we will deny CARE's motion.[141]

e. Applicability to Other Transactions

The ISO argues that the exclusion of spot purchases made by the ISO pursuant to DOE orders is at odds with DOE regulations that govern DOE Orders which presume that the ensuing charges will be in conformity with existing Commission standards. The ISO states that 10 C.F.R. § 205.376 explains how rates and charges for services provided under section 202(c)) of the FPA are to be determined, i.e., services provided under section 202(c)) are to be settled in accordance with established Commission formula rates. The ISO asserts that it relied on the rate regime that the Commission had in place at the time, i.e., the $150/MWh breakpoint. PSColorado seeks clarification that out-of-market sales transacted pursuant to DOE orders are not subject to refund. It contends that these transactions are indistinguishable from other OOM transactions with the ISO.

San Francisco and Port of Oakland argue that short-term bilateral contracts should be made subject to refund. They argue that the prices in those contracts were as high and, thus, unjust and unreasonable, as spot market transactions made subject to refund.[142] They also argue that, since the Commission forced market participants to engage in short-term bilateral transactions, equity requires that the Commission make those transactions subject to refund. Port of Oakland also argues that the July 25 Order erroneously focused on the type of contract rather than the level of the rate in determining whether prices are unjust and unreasonable. It argues that the FPA does not make a spot market/bilateral contract distinction, but instead requires that all wholesale power sales be at just and reasonable rates. Port of Oakland also contends that the spot and bilateral markets are part of an integrated California market and should not be treated separately for purposes of refunds. It contends that trading counterparties rely upon spot market indices to determine the prices under bilateral contracts, and if spot market prices are unjust and unreasonable, the basis for bilateral contracts, in turn, is also unjust and unreasonable.

Commission Response

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[141]Mirant correctly concludes that its contracts with DWR were not required to have been filed.

[142]See also Request for Rehearing of California Parties at 5-6, describing sellers' purported market power in bilateral markets.

The ISO states that it relied on DOE regulations when entering into transactions pursuant to DOE section 202(c)) orders. However, the FPA itself is the primary authority for determining rates for those transactions, and section 202(c)) provides:

> If the parties affected by such order fail to agree upon the terms of any arrangement between them in carrying out such order, the Commission, after hearing held either before or after such order takes effect, may prescribe by supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party.

The statute provides no role for the Commission in the event the parties agree on the rates that will apply to the transactions. In the case of the sales at issue here, the parties agreed on the terms and rates for the sales. Thus, the statute provides for no further adjustments. The fact that DOE regulations offered guidance referencing Commission decisions does not change the statutory provisions. Nothing the ISO argues convinces us that these transactions are to be brought within the scope of this proceeding.

We clarify for PSColorado that OOM sales transacted pursuant to DOE orders are similarly not subject to refund. Although the ISO negotiated directly with parties to obtain both types of OOM sales, parties should be able to distinguish between them because of the way they were procured by the ISO. After issuance of an order from DOE for a particular day, the ISO notified specific market participants whose resources were needed the following day to meet forecasted system demand pursuant to the DOE order. Ensuing negotiations would thus have been informed by that notification.

We are not convinced that any other short-term bilateral contracts may be made subject to refund under the July 25 Order. As discussed above, bilateral transactions are beyond the scope of the SDG&E proceeding. SDG&E's initial complaint targeted only sales of energy and Ancillary Services into markets operated by the ISO and the PX, not bilateral sales. Although the Commission found it appropriate after the DOE section 202(c)) order to apply prospective price mitigation to bilateral spot markets in the WSCC, including California,[143] this action was taken as part of the section 206 investigation of the WSCC markets. Imposing refund liability on bilateral transactions in the SDG&E proceeding is not permitted.

f. The October 2, 2000 Refund Effective Date

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[143] See June 19 Order at 62,556.

Some parties oppose the establishment of October 2, 2000 as the refund effective date.[144] For example, the Marketer Group argues that the Commission has not addressed EPSA's argument, raised on rehearing of the November 1 Order, that, because the Commission dismissed the remedy sought by SDG&E and initiated a broader investigation, the case was an investigation created by the Commission on its own motion and that the refund effective date should be October 29, 2000, which was 60 days from the date of Federal Register publication of the August 23 Order initiating the broader investigation. According to the Marketer Group, this conclusion flows from the purpose of the 60-day prior notice requirement, which involves giving targets of an investigation reasonable notice. It argues that, for a complaint, the complainant must serve a copy of the complaint on the defendant contemporaneously with the filing of the complaint; thus, it makes sense for the refund effective date to be 60 days from the date the complaint is filed. By contrast, Marketer Group argues that when the Commission initiates a proceeding, it does not serve the potential defendants. Instead, the Commission publishes notice in the Federal Register; thus, the refund effective date is 60 days after Federal Register publication. In either case, Marketer Group argues, the point is to have the 60 days start running on the day the defendant can reasonably be expected to have notice of the magnitude of the charges against it.

Portland General and Reliant argue that refunds for transactions that already have been reported and that did not receive notification of potential refunds within the 60-day review period established in the December 15 Order should be excluded from the refund hearing. Portland General seeks clarification on this issue.

PG&E maintains that the Commission is able to order refunds for the pre-October 2000 period if it determines that it committed legal error in the August 23 Order when it denied SDG&E's request for a price cap. It requests refunds going back to May 2000, or at least back to August 2000.

Commission Response

We deny rehearing concerning the establishment of October 2, 2000 as the refund effective date, as discussed below.

EPSA's argument that the August 23 Order is a rejection of SDG&E's complaint and Marketer Groups' argument concerning notice of the initiation of the Commission's investigation are not persuasive. In denying SDG&E's request for an immediate price cap on all sellers into the ISO and PX markets, the August 23 Order did not dismiss

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[144] See, e.g., Requests for Rehearing of Marketer Group, Dynegy.

SDG&E's complaint in Docket No. EL00-95-000. Although the August 23 Order denied SDG&E's request for summary disposition (i.e., the immediate imposition of a price cap) as too narrowly focused on seller conduct and unsupported, based on the facts then available, the August 23 Order nonetheless set the issue of the justness and reasonableness of sellers' rates in the ISO and PX markets for investigation.[145] Further, the investigation initiated in Docket No. EL00-98-000 concerned whether market rules or institutional factors embodied in the ISO's and PX's tariffs and agreements contributed to the unusually high rates and needed to be modified.[146] Thus, the investigation in Docket No. EL00-98-000 did not supersede the rate investigation in the complaint docket; it complemented the rate investigation. The August 23 Order thus established two separate, but related, investigations -- Docket No. EL00-95-000 concerning sellers' rates in the ISO and PX markets and Docket No. EL00-98-000 concerning whether the ISO and PX market rules or institutional factors were flawed and required modification -- and consolidated them for purposes of hearing and decision in view of their common issues of law and fact.

Section 206 of the FPA requires the Commission to establish a refund effective date "whenever the Commission institutes a proceeding under this section."[147] In a complaint proceeding, the Commission may establish the refund effective date anywhere from 60 days after the filing of the complaint to five months from the expiration of the 60-day period. In an investigation initiated on its own motion, the Commission may establish a refund effective date anywhere from 60 days after publication of notice of its intent to initiate a proceeding to five months after the expiration of the 60-day period. The Commission's policy is to establish the earliest refund effective date allowed in order to give maximum protection to consumers.[148] The SDG&E complaint docket involves all sellers' rates in the ISO and PX markets. All sellers receive the market clearing price (unless they successfully justify a bid higher than the mitigated Market Clearing Prices), and all three of the IOUs were required to make their wholesale purchases through the

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[145] August 23 Order, 92 FERC at 61,609, Ordering Paragraph (B) (ordering a public hearing in Docket Nos. EL00-95-000 and EL00-98-000) and Ordering Paragraph (D) (consolidating Docket Nos. EL00-95-000 and EL00-98-000 for purposes of hearing and decision).

[146] 92 FERC at 61,605-06.

[147] 16 U.S.C. § 824e(b) (1994).

[148] See, e.g., Indiana Municipal Power Agency v. PSI Energy, Inc., 85 FERC ¶ 61,073 (1998); Canal Electric Co., 46 FERC ¶ 61,153, reh'g denied, 47 FERC ¶ 61,275 (1989).

ISO and PX from October 2, 2000 through January 1, 2001. Any refunds applicable to SDG&E thus would apply to PG&E and SoCal Edison as well. The earliest permissible refund effective date, which afforded maximum protection to consumers, was October 2, 2000.

Marketer Group's argument concerning notice to affected parties of section 206 proceedings rests on the premise that the August 23 Order rejected SDG&E's complaint and that the investigation in Docket No. EL00-98-000 superseded the complaint proceeding. That was not the case, as discussed above. Thus, Marketer Group's argument is not persuasive. Further, the cases cited by EPSA are distinguishable. In Sierra Pacific Power Co.,[149] the Commission addressed two different proceedings – a section 205 filing of one agreement and requests for rehearing of an order accepting another agreement. On rehearing, the Commission reconsidered and determined that the previously accepted agreement should be set for hearing. However, it could not suspend a previously-accepted rate schedule, i.e., it could not, on rehearing, reverse its original decision not to suspend the rates. Rather, it had to set the matter for hearing under section 206 and establish a refund effective date. With respect to EPSA's argument that the Commission did not base the refund effective date upon the date of the protests, we note that the Commission has determined that it will not treat protests as complaints. That has no bearing on this case, however, because SDG&E filed the complaint in this case.[150] Further, although the Commission may not, on rehearing, reverse a decision not to suspend a rate filing, it may change the refund effective date on rehearing of an order establishing the refund effective date. The order establishing the refund effective date was not a final order, as rehearing of that order was available.[151] Requests for rehearing

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[149]86 FERC ¶ 61,198 (1999).

[150]EPSA also cites PacifiCorp, 74 FERC ¶ 61,163 (1996), for the proposition that the Commission established one refund effective date based upon the date of the complaint by customers concerning excessive rates but 60 days after notice of the Commission's further investigation for those rates not otherwise the subject of the complaints filed. That case is not persuasive. As noted above, the SDG&E complaint involves all sellers' rates in the ISO and PX markets. EPSA also cites Vermont Yankee Nuclear Power Co., 91 FERC ¶ 61,235 (2000), in which the Commission initiated a section 206 proceeding from rate concerns raised in a section 203 proceeding. No such facts are presented here. As noted above, the instant proceeding was initiated, in pertinent part, by SDG&E's complaint, which the Commission expressly set for hearing.

[151]See, e.g., Florida Power Corp., 65 FERC ¶ 61,040 at 61,412-13 (1993) ("[J]ust as the decision to suspend a rate increase for five months rather than one day must be

(continued...)

of the August 23 Order raising the refund effective date issue were timely filed. Thus, any reliance by sellers on the October 29 refund effective date prior to issuance of a final order was at their own risk.

PG&E's contention that the Commission has authority under the FPA to order refunds for the period prior to October 2, 2000 relies on our authority to set just and reasonable rates, but the issue here concerns retroactive refunds of unjust and unreasonable rates. These are two separate issues, each with its own governing principles.

Our authority under FPA section 206 to set new rates is prospective only; if we find that rates no longer meet the just and reasonable standard, we are authorized only to fix a new rate or to fix practices "to be thereafter observed."[152] As a separate matter, FPA section 206 provides us with limited refund authority. While section 206 as originally enacted did not provide for refunds, Congress amended the provision to permit us to order refunds effective no earlier than 60 days after the date that a complaint is filed or the Commission initiates an investigation.[153] Therefore, section 206 does not permit retroactive refund relief for rates covering periods prior to the refund effective date established on complaint or the initiation of a Commission investigation, even if the Commission determines that such past rates were unjust and unreasonable.

PG&E's reliance on a "legal error" theory to circumvent the statutory limitation on refunds is flawed. The Commission did not commit legal error regarding its oversight of the California markets, as PG&E asserts.[154] In any event, the legal error theory is wholly

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[151](...continued)
challenged at the beginning of the proceeding, when that decision is made, so the decision to select an RFA refund effective date must be challenged at the time that decision is made (when the Commission establishes the period for which refunds can be ordered)."), reh'g rejected and reconsideration denied, 66 FERC ¶ 61,200 (1994).

[152]16 U. S.C. § 824e(a) (1994).

[153]Regulatory Fairness Act of 1988 (RFA). S. Rep. No. 491, 100th Cong., 2d Sess. 3-4 (1988), reprinted in 1988 U.S.C.C.A.N. 2685.

[154]PG&E Rehearing Request at 19-20 and n.38 ("The Commission has the ability to order refunds for the pre-October period if it acknowledges that allowing the California markets to operate unhindered initially was legal error," citing the Commission's August 23, 2000 Order, 92 FERC ¶ 61,172, denying SDG&E's request for (continued...)

inapplicable. That theory may permit the Commission to order refunds as a remedy to correct legal errors found by an appellate court upon judicial review.[155] No such finding has been made here.

g. Duration of Price Mitigation

A number of parties request rehearing of the termination date established in the June 19 Order as unsupported by substantial evidence that the market will operate effectively by that date, or clarification that the Commission will review conditions in California and the WSCC before it terminates the mitigation plan.[156] Conversely, Tucson and Mirant contend on rehearing of the June 19 Order that the Commission failed to justify extending the termination date past the April 2002 date specified in the April 26 order. Duke requests clarification of the June 19 Order that the Commission may further modify the mitigation plan prior to the commencement of the summer season in 2002, depending upon market conditions at the time of the March 2002 compliance filing.

PG&E requests clarification that the refund methodology established in the July 25 Order was not intended to supersede the $150 breakpoint methodology that was established in the December 15 Order, as it applied to the markets operating from January 1, 2001 to May 28, 2001. Absent such clarification, PG&E seeks rehearing.

PG&E states that, in informal discussions, some sellers have suggested that the July 25 Order applies only to non-emergency hours, but does not apply to hours that were addressed in the March 9 Order. PG&E requests clarification that the July 25 Order's

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[154](...continued)
a $250/MWh price cap on all sales into the ISO and PX markets).

[155] See United Gas v. Callery Properties, 382 U.S. 223, 229 (1965) (while the Commission has no power to make reparation orders, its power to fix rates being prospective only, it is not so restricted where its order, which never became final, has been overturned by a reviewing court); Reynolds Metals Co. v. FERC, 777 F.2d 760, 763 (D.C. Cir. 1985); Public Utilities Commission of the State of California v. FERC, 988 F.2d 154, 161-162 (1993) (allowing pipeline to seek retroactive recovery of costs based on court reversal of FERC order, citing "general principle of agency authority to implement judicial reversal").

[156] See, e.g., Requests for Clarification and Rehearing of Attorney General of Washington/City of Tacoma, Washington and Port of Seattle, Washington, ISO, Metropolitan, and Washington Attorney General.

refund methodology applies to all hours from January 1, 2001 to May 28, 2001, including the emergency hours that were previously capped using the proxy price methodology adopted in the March 9 Order.[157] Absent such clarification, PG&E seeks rehearing. PG&E contends that the July 25 Order's methodology corrects deficiencies in the March 9 Order's methodology.

Commission Response

We deny these requests for rehearing. In the June 19 Order, we cited our requirement that the ISO file a report on market conditions by March 26, 2002 that addresses, among other things: a list of all new generating resources that the State of California has announced would be on line by summer 2002 and which of those facilities are on line;[158] and the continued progress in executing long-term contracts and reducing reliance on the spot market.[159] Further, the June 19 Order continued the April 26 Order's requirement that the ISO file quarterly reports, beginning on September 14, 2001, analyzing how the mitigation plan is operating and the progress that has been made in developing new generation and demand response.[160] In a recent Commission order, the Commission explained that if there is not a sufficient Commission-approved superseding mitigation plan in place after September 30, 2002, all sellers into the ISO market will need to undergo review of their market-based rate authority based on the Supply Margin Assessment screen or such other Commission-approved market power analysis in place

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[157]We interpret PG&E's request to be in the alternative to its request for clarification concerning the $150 breakpoint methodology, discussed above.

[158]The April 26 Order and the June 19 Order noted that the State committed itself to increasing in-state generation and that the State projected that new generation totaling 4,168 MW would be on line by the end of August 2001 and that there could be as much as 6,879 MW on line for the summer of 2002. See June 19 Order, 96 FERC at 62,567 & n.85. According to the ISO's web site: 2,231 MW of generation capacity was added to the ISO control area as of September 2001; another 1,612 MW of new capacity is expected to become operational by the end of 2001; and during 2002, an additional 6,490 MW of new capacity is expected to be added based on currently announced plans. (See ISO Web Site, 2001/02 Winter Assessment Report, pp. 5-6, 10 (Oct. 8, 2001).)

[159]95 FERC at 62,567.

[160]Id.; see also April 26 Order, 95 FERC at 61,365. The Commission will review comments on the ISO's reports and determine whether any element of the mitigation plan warrants adjustment.

at that time.[161] We also note that the April 26 Order conditioned sellers' continuing market-based rate authority on their not engaging in certain anticompetitive behavior, with violators' market-based rates being made subject to refund.[162]

In response to the parties who oppose extending price mitigation to September 30, 2002, as noted above, the June 19 Order identified getting new generation on line as one of the key elements of having markets perform properly. Further, the State has targeted the summer of 2002 for bringing much of that new generation on line. Therefore, it is appropriate to extend price mitigation through the summer of 2002 (i.e., through September 30, 2002) in order to help ensure that an imbalance of supply and demand is not continuing to hamper proper performance of the markets before price mitigation ends.

With respect to PG&E's requests for clarification, we clarify that the July 25 refund methodology applies to all hours from October 2, 2000 through May 28, 2001. Thus, the refund methodology established in the July 25 Order supersedes the $150 breakpoint methodology for that period. For the period from May 29, 2001 through June 20, 2001, the April 26 price mitigation measures will apply to reserve deficiency hours;[163] the mitigated price for non-reserve deficiency hours will be calculated in the refund hearing before Judge Birchman.[164] This approach reflects the July 25 Order's adoption, with modifications therein, of the recommendation of the Chief Judge in the

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[161]Huntington Beach Development, L.L.C., 96 FERC ¶ 61,212, reh'g denied, 97 FERC ¶ 61,256 (2001).

[162]We further note that the Commission recently issued an order pursuant to section 206 of the Federal Power Act proposing to revise all existing market-based rate tariffs and authorizations to include a provision prohibiting the seller from engaging in anticompetitive behavior or the exercise of market power. Order Establishing Refund Effective Date and Proposing to Revise Market-based Rate Tariffs and Authorizations, 97 FERC ¶ 61,220 (2001).

[163]The July 25 Order noted that there was a gap from May 29 through June 20, 2001, when price mitigation only applied to periods of reserve deficiencies. In order to maintain a consistent approach during all periods of time, the July 25 Order required application of the refund calculation discussed therein to the non-reserve deficiency hours from May 29 through June 20, 2001. Transactions that occurred during reserve deficiency hours in that period, already mitigated as a result of the April 26 Order, were not affected. The June 19 Order mitigates prices in all hours, effective June 21, 2001.

[164]96 FERC at 61,517, 61,520.

settlement proceeding that the Commission should apply a consistent methodology to the entire refund period.

2. Calculation of Mitigated Prices

a. Use of Marginal Cost of Last Unit Dispatched

i. June 19 Order

On rehearing of the June 19 Order, APPA argues that the Commission's mitigated market clearing price methodology fails to establish separate and distinct prices based on the costs of production for each major zone within the ISO and for regional market hubs within the WSCC and that it likewise fails to pay sellers based on the marginal prices within each such zone. According to APPA, a single price approach will produce unreasonable results and may allow the exercise of market power whenever interregional transmission constraints limit imports into California, or on Path 15 between northern and southern California. Therefore, APPA considers the Commission's approach reasonable only on an interim basis.

Enron and Reliant request clarification of the June 19 Order that the mitigated Market Clearing Prices be known at the time a sale is confirmed. They contend that the current mitigated Market Clearing Prices, which can change hourly and without notice, do not provide the certainty the Commission supports. They request clarification that the mitigated Market Clearing Prices in effect at the time the deal is transacted, rather than the mitigated Market Clearing Prices in effect when delivery takes place, will apply to the transaction.

Dynegy requests clarification of the June 19 Order that the mitigated reserve deficiency MCP will be based on the marginal cost of the least efficient unit serving load in the ISO spot markets and should not be based solely on the last unit dispatched in the ISO's BEEP stack. Dynegy claims that the BEEP stack is limited to supplemental energy bids and the energy portion of Ancillary Services bids, which should be limited to no more than 5 percent of the market, and excludes other ISO spot market energy sales. Furthermore, Dynegy claims that the ISO can too easily disqualify units from setting the mitigated reserve deficiency MCP by labeling them "out of market" or "out of sequence" if the mitigated reserve deficiency MCP is based solely on BEEP stack transactions.

Reliant requests clarification of the June 19 Order that the mitigated reserve deficiency MCP is to be set by the proxy price of the last unit dispatched, not the lower

of the marginal costs or the actual bid of the marginal unit.[165] According to Reliant, the June 19 Order fails to correct the ISO's misapplication of the April 26 Order's requirement to set the mitigated reserve deficiency MCP based on the highest cost dispatched gas-fired generator. However, Reliant complains that the ISO has proposed in its May 11, 2001 compliance filing to establish the mitigated reserve deficiency MCP at the lower of the actual bid or the marginal costs of the last unit dispatched, as calculated according to the June 19 Order.

Commission Response

In the June 19 Order, the Commission found it appropriate to mitigate all sales in the WSCC spot markets based on the ISO mitigated Market Clearing Prices. The Commission found it critical to treat all sellers alike to remove the incentive to sell in one area versus another. Furthermore, the Commission pointed out that since there is no centralized clearing house for spot market sales in the WSCC other than the ISO, there is no ability to develop a separate market clearing price for sales outside the ISO. Therefore, we deny APPA's requested modification.

Dynegy's request for clarification that the mitigated reserve deficiency MCP will be based on the marginal cost of the least efficient unit serving load in the ISO spot markets and should not be based solely on the last unit dispatched in the ISO's real time Imbalance Energy market pertains to the ISO's July 11 compliance filing; that filing will be addressed in a separate order to be issued concurrently with this order. In that order, we explain that units dispatched through the Imbalance Energy market are the marginal units and thus are the only units that can set the mitigated reserve deficiency MCP.

With respect to Reliant's request for clarification that the mitigated reserve deficiency MCP is to be set by the Proxy Price of the last unit dispatched, rather than the lower of the Proxy Price or the actual bid of that marginal unit, we clarify that the proxy price alone should set the market clearing price. As explained in our order on compliance to be issued concurrently with this order, we specifically rejected requests to use alternative methods, such as a generator's actual costs, to set the mitigated reserve deficiency MCP, concluding that "[t]he Commission's mitigation plan is designed to establish a generators' bid and market prices up-front."[166] In imposing mitigation, we are no longer relying on the market. Instead, the mitigation substitutes a prescribed method for computing the mitigated reserve deficiency MCP during periods of reserve

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[165] Request for Expedited Clarification of Reliant Energy Power Corp. and Reliant Energy Services, Inc.

[166] June 19 Order at 62,560.

deficiency so as to replicate a competitive market by using an identified and consistent set of cost data. The ISO's use of alternative data violates our prescribed methodology and is therefore rejected.

ii. July 25 Order

PSColorado argues on rehearing of the July 25 Order that relying on actual heat rate data requires the assumption that imports into California markets would have remained at the same volume even if those suppliers outside of California faced the prospect of much lower prices (i.e., the resulting mitigated Market Clearing Prices). However, the company asserts, a reduction in prices would have led to fewer imports and a corresponding increase in intra-California generation and thus a higher heat rate for the marginal unit. Thus, the argument follows, use of the actual heat rates substantially understates the marginal costs under mitigated prices, and PSColorado argues that the Commission should instead set a mitigated market clearing price that accurately reflects the actual market conditions affecting California during the refund period, specifically, by keying refunds to a generic proxy price based on a relatively inefficient unit. AEPCO raises the same issue but suggests taking into account the heat rates of out-of-California sellers that exceed the highest California heat rate. Dynegy seeks rehearing of the Commission's implicit decision that only in-state generators may set the mitigated reserve deficiency MCP.

Parties representing purchasers argue the opposite, that utilizing the heat rate of the actual unit dispatched increases the mitigated reserve deficiency MCP.[167] These parties believe that, by withholding capacity, generators forced the ISO to dispatch less efficient units. They conclude that the marginal cost of the last unit dispatched did not represent a competitive market price, and suggest instead determining the highest heat rate of all units that were not, but could have been, dispatched as if these units were dispatched in economic merit order. PG&E asserts that least cost dispatch should be used, and that parties should be permitted to argue for such at the hearing before Judge Birchman, if the Commission finds a pattern of improper withholding.

Indicated California Generators request rehearing of the method of determining the highest marginal cost unit dispatched in real time. The companies assert that the Commission's approach mistakenly focuses on identifying the unit with the highest heat rate and instead "should apply the 'North' gas cost index to the unit in the North with the highest heat rate, and apply the 'South' gas cost index to the unit in the South with the

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[167] See, e.g., Requests for Rehearing of California Parties, PG&E, ISO.

highest heat rate. Whichever unit has the highest total costs should serve as the system-wide marginal, market clearing unit."[168]

Duke notes that the Commission has imposed refunds on all transactions in a variety of ISO and PX markets, yet allows units operating in only one market -- the ISO's real-time market -- to set the mitigated Market Clearing Prices for them all. Dynegy similarly argues that any generating unit used to sell into any of these markets should be able to set the mitigated price. Duke alleges that market dynamics in some other markets are quite different from those in the ISO real-time market, and charges that the Commission erred by not allowing suppliers the opportunity to present evidence on an appropriate methodology for setting different mitigated prices for the various markets.

Commission Response

We are not persuaded by PSColorado's arguments that the volume of imports would have changed considerably if different heat rate data were used to calculate the mitigated reserve deficiency MCP, or that imports would have significantly affected the resulting Proxy Prices. It is the Commission's understanding that, for technical reasons, out-of-state generators' participation in the ISO's real-time market is minimal.[169] Thus, we do not believe that the proxy price is understated. Moreover, any effort to implement PSColorado's premise would be extremely speculative. Indeed, the Commission selected a remedy with theoretical underpinnings that, at the same time, could be reasonably implemented.[170]

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[168]Request for Rehearing of Indicated California Generators at 3. See also Requests for Rehearing of Dynegy, Reliant, Portland General.

[169]See, e.g., California Independent System Operator Corporation, 91 FERC ¶ 61,324 at 62,115-16 and 62,118 (2000), reh'g pending (Amendment No. 29 Order).

[170]The Commission has freedom, "within the ambit of [its] statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances. "FPC v. Natural Gas Pipeline Co., 315 U.S. 575, 586 (1942); In re California Power Exchange Corp., 245 F.3d 1110, 1120 (9th Cir. 2001). FPA section 309, 16 U.S.C. § 825h (1994), gives the Commission the necessary flexibility to take unusual remedial action in appropriate circumstances. See Permian Basin Area Rate Cases, 390 U.S. 747, 776 (1968) (applying NGA section 16, the counterpart of FPA section 309, the Court held that "the Commission's broad responsibilities . . . demand a generous construction of its statutory authority."); FPC v. Louisiana Power & Light Co., 406 U.S. 621, 642 (1972) (same).

We are also not persuaded that the marginal costs are overstated. The ISO and other parties raised the same arguments in response to the Chief Judge's Recommendation, and the July 25 Order discussed at length why this approach (a simulation of the must-offer requirement, or "assumed economic dispatch") would not be appropriate. In the July 25 Order, the Commission explained that we did not institute the must-offer requirement or the marginal bidding requirement until May 29, 2001, and that it was unreasonable to require that the markets be recreated to, in effect, apply those requirements to the refund period. In addition, the Commission noted that generators actually dispatched had specific marginal costs that are reasonably recovered. The Commission concluded that the end result of using an assumed economic dispatch would be to unfairly lower prices below the actual marginal costs of the last generator dispatched.

On rehearing, California Parties and others focus on purportedly "unrefuted evidence that sellers exercised withholding" and argue that the Commission's approach allows the sellers to retain the fruits of their acts. The "unrefuted evidence" of withholding cited by parties consists of analyses of bidding behavior that, through economic inference, conclude that sellers' bidding strategies resulted in market clearing prices rising above competitive levels. Any firm evidence of strategic withholding will be pursued seriously by the Commission; however, these studies do not rise to that level because they are simply based on assumptions. They do not persuade us to impose an assumed economic dispatch, a hypothetical dispatch, for past periods. We believe our refund methodology ensures just and reasonable rates as required by the FPA; we are under no obligation to make, or recreate, a perfect market based on a hypothetical dispatch of resources.

We will clarify for Dynegy and AEPCO that we will permit prospectively out-of-state generators to set the mitigated reserve deficiency MCP. The June 19 Order specified that out-of-state generators that want to have their marginal costs included in calculating the mitigated reserve deficiency MCP can provide the required heat rate and gas source data to the ISO.

We will grant Indicated California Generators' rehearing request. They correctly describe the appropriate method for determining the mitigated reserve deficiency MCP using separate gas cost indices for northern and southern California, which will lead to the best approximation of the marginal costs of the last unit dispatched. Therefore, we will direct the ISO to recalculate the mitigated reserve deficiency MCP for each hour of the refund period in the manner prescribed in our orders, as modified by the Indicated California Generators, and to provide the data to Judge Birchman for use in the refund hearing. We will permit Judge Birchman to revise the hearing schedule as needed to accommodate these additional calculations.

The arguments of Duke and Dynegy regarding mitigated prices in other ISO markets are similar to those addressed in the section on the treatment of Ancillary Services.[171] As we explain there, it is appropriate to have separate market clearing prices for each Ancillary Service, capped by the Imbalance Energy mitigated reserve deficiency MCP.

b. Gas Costs

i. June 19 Order

Many generators seek rehearing of the Commission's revision to the gas cost formula in the June 19 Order.[172] They argue that the proxy gas price based on the Commission formula bears no relationship to the gas prices actually incurred by generators.[173] They also argue that the gas cost methodology will impede suppliers' recovery of operating costs while subject to a must-offer requirement;[174] that it understates gas costs by directing the ISO to average the mid-point of the monthly bid-week prices reported for three spot market prices for California;[175] that it fails to account for the in-state costs of natural gas transportation;[176] and that it ignores the fact that gas is purchased at different locations in California depending on the location of the generating unit.[177]

Mirant contends that the gas cost formula is inconsistent with the rationale underlying the Commission's price mitigation scheme. Mirant states that in the April 26 Order the Commission excluded a fixed cost adder because the single-price auction mechanism allows most generators to recover some contribution to their capital costs. However, Mirant asserts, the June 19 Order departed from the concept of a single price auction by revising the gas cost formula to reflect average monthly gas costs and

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[171] See supra, section B.2.g.

[172] See e.g., Requests for Rehearing of Calpine, Duke, Dynegy, EPSA, Enron, Idaho Power, IEP, Mirant and Reliant.

[173] See, e.g., Request for Rehearing of Calpine.

[174] See, e.g., Request for Rehearing of Duke.

[175] See, e.g., Request for Rehearing of EPSA.

[176] See, e.g., Requests for Rehearing of EPSA and Reliant.

[177] See, e.g., Request for Rehearing of EPSA.

excluding emissions costs. Mirant contends that this change has significantly expanded the number of generators who will not be able to recover their variable costs and who will therefore not obtain a contribution to their fixed costs through the mitigated reserve deficiency MCP.

Generators recommend: (1) terminating the averaging of gas costs;[178] (2) using separate prices for deliveries in northern and southern California;[179] (3) including intrastate transportation charges and other gas costs in the mitigated reserve deficiency MCP;[180] (4) providing for gas imbalance penalties as an uplift charge;[181] and/or (5) using daily rather than monthly gas costs based on published indices and hubs that are actually used by traders to secure gas for California generating plants.[182]

Reliant and Duke request clarification of the June 19 Order as to how the use of "gas source" data for out of state generators is to be applied. Idaho Power recommends that the mitigated reserve deficiency MCP for sales in the Pacific Northwest (i.e., the states of Washington, Oregon, Idaho, Montana, Wyoming and Utah) should be based on the published spot gas prices for Northwest Pipeline Corporation's Canadian Border (Sumas, WA) and Rocky Mountain (Opal, WY) delivery points.

Commission Response

We find that the gas cost methodology established in the June 19 Order will not impede suppliers' recovery of operating costs and should be maintained. While both the Chief Judge and the Commission recognized in the July 25 Refund Order that, over the prior period, generators procured gas on a spot basis to support spot electric sales,[183] the Commission determined in the June 19 Order that it is appropriate for the prospective period to require the use of monthly gas costs to address and influence purchasing decisions for prospective sales. As the Commission explained in the June 19 Order, the

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[178] See, e.g., Request for Rehearing of Dynegy.

[179] See, e.g., Request for Rehearing of Calpine.

[180] See, e.g., Request for Rehearing of Dynegy.

[181] See, e.g., Request for Rehearing of Dynegy.

[182] See, e.g., Requests for Rehearing of Enron and Mirant.

[183] Report and Recommendation of the Chief Judge and Certification of Record, 96 FERC ¶ 63,007 (2001); July 25 order at 61,517-18.

mitigation plan is designed to establish generators' bids and market prices ahead of time. The Commission found that the average pricing formula "represents a reasonable proxy for the marginal costs that generators will incur, since they can pre-buy their gas requirements for the month at this price."[184] The Commission determined that it is inappropriate in the context of prospective mitigation to use actual costs because that approach would not provide price transparency and because it would require burdensome post hoc reviews of generator bids.[185]

Suppliers complain that the averaging of the mid-point of the monthly bid-week prices reported for three spot market prices for California will under-compensate generators located in higher gas cost areas in Southern California. They also contend that there is no compensation for intrastate gas transmission costs. In the June 19 Order the Commission recognized that there are intrastate gas transmission constraints in Southern California and other factors that have led to higher reported prices in that region. However, the Commission identified concerns regarding the reliability of the reported gas prices in southern California as a predictor of actual prices paid by generators in that region.[186]

Furthermore the Commission pointed out that suppliers have two alternatives if they find they are not fairly compensated for these costs.[187] First, individual generators may justify bids above the mitigated Market Clearing Prices so long as they can show their entire gas portfolio justifies such a bid. Alternatively, they may file under cost of service rates as to their portfolios. Under either approach, suppliers are assured that they will be compensated for their gas costs.

Finally, we disagree with Mirant's argument that the gas cost formula is inconsistent with the Commission's premise that the proxy price should be based on the least efficient generator. In the context of prospective mitigation, as noted above, generators should be able to purchase gas at the prices used in the mitigation formula.

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[184] June 19 Order at 62,561.

[185] Id.

[186] Among other things, the Commission explained in the June 19 Order that it is unclear what volume of gas moves at the prices reported by Gas Daily and other reporting services, and that the higher prices reported for Southern California may not necessarily be paid by generators who may hedge their gas costs or buy on a forward basis.

[187] June 19 Order at 62,564.

We decline to set prices based on the higher costs of those who forego this opportunity. Accordingly, we continue to believe, that for the prospective price mitigation covered by the June 19 Order, the average gas cost method achieves an equitable balance of our concerns regarding the reasonableness of pricing gas costs based on reported prices in Southern California, providing prospective price transparency, and ensuring that generators are compensated for their gas costs.

In response to Reliant's and Duke's requests for clarification, we clarify that out-of-California generators are to use the same gas source data as is used for generators in California. While we recognize that these generators do not purchase gas at the California source points, gas prices have been higher in California during the summer months relative to the remainder of the West. Therefore, we expect that out-of-state generators will be fully compensated for their gas costs during the summer. Gas pricing for the period following the summer of 2001 is the subject of an inquiry in Docket No. EL01-68-000 and is addressed in an order issued concurrently with this order.[188]

ii. July 25 Order

The Commission held in the July 25 Order that gas costs for past periods should be determined by using the daily spot market price for gas, rather than the monthly bid-week prices used in the June 19 Order. The Commission also separated the state's gas market into northern and southern zones, applying a northern and southern gas cost depending on whether the marginal unit is located in northern or southern California. The Commission supported the use of daily prices based on: (1) evidence presented before Judge Wagner that generators purchased gas at spot prices for generating electricity for sales into spot markets; (2) Commission precedent using spot purchases to calculate the replacement cost of fuel; and (3) the fact that the June 19 approach intended to address and influence purchasing decisions for prospective sales, while the refund methodology applied to past periods.[189]

The Oversight Board, California Parties, City of San Diego and PG&E object to the use of daily spot gas prices, arguing that there was insufficient evidence in the record to determine that generators purchased gas at spot prices. They point out that the

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[188]This inquiry relates to the technical conference which staff conducted on October 29, 2001 regarding West-wide price mitigation for the winter season. See Investigation of Wholesale Rates of Public Utility Sellers of Energy and Ancillary Services in the Western Systems Coordinating Council, Docket No. EL00-68-000, 97 FERC ¶ _____ (2001).

[189]July 25 Order, 96 FERC at 61,517-18.

evidence before Judge Wagner consisted of testimony of a single generator and that other parties had no opportunity to cross-examine the witness or to present conflicting evidence. They also contend that the Commission punishes California customers by not "recreating" gas purchasing behavior, asserting that the use of actual cost data, or the approach adopted in the June 19 Order, would be more accurate, and they charge that the higher spot prices may have resulted from manipulation in the gas market. Many of these parties also assert that the Commission should allow for further adjustments to gas prices based on a final decision in Public Utilities Commission of the State of California v. El Paso Gas Co., et al., 94 FERC ¶ 61,338, order on reh'g, 95 FERC ¶ 61,368 (2001) (El Paso), investigating manipulation of gas prices in California.[190]

PG&E challenged the Chief Judge's recommendation previously, and in the July 25 Order, the Commission responded that the PG&E had not refuted the evidence relied on by the Chief Judge. On rehearing, PG&E states that "evidence concerning sellers' gas purchasing has never been made available in discovery, or through any other means."[191] Therefore, PG&E asserts that the Commission should return to the June 19 Order's approach or it should provide additional data gathering process.[192] San Diego points out that disputes about the proper gas price can be eliminated by using the marginal generator's actual gas costs.

Mirant challenges the use of gas prices at both Malin and PG&E Citygate hubs for calculating the proxy price for Northern California transactions because gas prices at Malin are irrelevant to a determination of a Bay Area supplier's actual gas costs, and urges the use of only PG&E Citygate.

Commission Response

While the purchasing practices of a single generator cannot be assumed to apply to the entire industry, we historically have used spot prices to calculate the replacement cost of fuel. We find it appropriate to apply that policy here. Because gas fired generators

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[190]See, e.g., Requests for Rehearing of ISO, San Diego, PG&E and California Parties.

[191]Request for Rehearing of PG&E at 7.

[192]On September 20, 2001, PG&E filed a motion to submit newly obtained evidence in support of its rehearing request consisting of data obtained in response to discovery requests in the refund hearing that it alleges refutes the evidence relied upon by the Chief Judge. This order rejects the motion as an untimely supplemental rehearing request. See supra, section A.

have not been considered core customers on the local gas distribution systems in California, they have had no rights to firm transportation capacity on either LDCs or upstream pipelines, and thus, have had to rely on gas spot markets. Accordingly, we believe that using daily spot prices for the refund methodology is most likely to capture the costs that units actually paid. Thus, no additional process is required. Use of actual gas costs is not appropriate because they would not be transparent or readily verifiable, unlike spot market prices.

We will not decide here what adjustments, if any, are appropriate in the event refunds are ordered in the El Paso proceeding. The presiding judge issued an Initial Decision on October 9, 2001, finding that El Paso did not manipulate gas prices and recommending that refunds not be ordered.[193] In an order being issued concurrently we are requiring a limited reopening of the record to obtain additional evidence. We will resolve the question raised in this proceeding when we take final action in the El Paso proceeding.

The Commission addressed Mirant's issue in the July 25 Order, stating that if Mirant did not believe the gas prices used sufficiently covered its costs, it could file cost-based rates covering all of its units in the WSCC. Mirant raises no new arguments on rehearing to change our determination. The index price for northern California applies to all units throughout the northern part of the state; as an average of two prices, it will not represent the exact costs paid by any one generator, but will reasonably approximate what will be spent by the last unit dispatched for purposes of calculating the proxy price in northern California. Thus, use of this average is reasonable.

c. Emissions Costs

i. June 19 Order

A number of parties object to the Commission's directive in the June 19 Order that the ISO pass on to all users of the ISO grid emissions and start-up fuel costs through an uplift charge.[194] They argue that:

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[193] Public Utilities Commission of the State of California v. El Paso Gas Co., et al., 97 FERC ¶ 63,004 (2001).

[194] See, e.g., Requests for Rehearing of APPA, DWR, ISO, Southern Cities, City of Vernon, Cities/M-S-R, Metropolitan, Modesto, NCPA, and City of Redding.

- Such costs should be allocated only to those loads that are responsible for the spot market energy and Ancillary Services procured by the ISO and DWR on behalf of ISO loads;[195]
- Forcing ISO transmission customers to subsidize combustion turbine generators' billed (not necessarily incurred) costs for air pollution and start-up fuel violates principles of cost-causation, Order 888/2000 unbundling, and nondiscrimination, and requires cost of service payment without cost of service regulatory oversight;[196]
- The uplift charges for emissions and start-up fuel costs should be charged to all users of the ISO controlled grid, including exports to control areas outside California;[197]
- The June 19 Order improperly requires load-serving entities to pay start-up and emissions costs associated with energy used to serve loads supplied by others;[198] and
- The emissions surcharge deprives communities that have planned carefully for their emissions liabilities and needs of the benefit of their planning and forces them to pay for both their own planned-for emissions plus the emissions on generation purchased for other California customers.[199]

Generators contend on rehearing of the June 19 Order that the Commission erred in failing to account for start-up and emissions costs for generators outside of California.[200] Dynegy claims that the emission cost recovery mechanism inappropriately exposes generators to substantial future costs for which recovery might not be available.

APX requests clarification of the June 19 Order as to how a neutral exchange, such as APX, which does not take title, may implement the June 19 Order. APX contends that it should be allowed to adjust the contract price to the mitigated price and that a seller in such a contract should then be allowed to apply to the Commission for an

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[195]See, e.g., Request for Rehearing of APPA.

[196]See, e.g., Request for Rehearing of DWR.

[197]See, e.g., Request for Rehearing of ISO.

[198]See, e.g., Requests for Rehearing of Southern Cities, City of Vernon, Cities/M-S-R, Metropolitan, Modesto, NCPA, and City of Redding..

[199]See, e.g., Request for Rehearing of NCPA.

[200]See, e.g., Requests for Rehearing of Pinnacle West and PPL.

additional payment of emissions and startup costs from the buyer with the total payment limited by the contract price.

NRECA requests clarification of the June 19 Order that cooperatives making mandatory sales within the WSCC but outside of California should be able to collect their emissions costs without exceeding the otherwise applicable maximum price imposed by the Commission.

In addition, generators request clarification of the June 19 Order that extraordinary emissions and maintenance costs should be recovered as an addition to the O&M adder;[201] and that all environmental compliance fees, including mitigation fees, that are required for operation in accordance with ISO dispatch orders and the must-offer provisions are to be invoiced to the ISO.[202]

Commission Response

We will deny the requests for rehearing. As we stated in the June 19 Order, we believe that generators should be permitted to recover the cost of mitigation fees assessed when they are required to run in accordance with ISO dispatch instructions and the must-offer requirement.[203] The must-offer requirement is designed to ensure adequate supplies, which benefits all customers in California. Therefore, the administrative charge should be assessed against all load served on the ISO's system. We will not allow generators to bill the ISO for capital improvements that may serve to reduce their emissions costs. Fixed costs associated with such improvements are not within the scope of the emissions allowance.

As noted above, the June 19 Order directed generators that are required to run in accordance with ISO dispatch instructions and the must-offer requirement to invoice the ISO directly for actually incurred emissions and start-up fuel costs.[204] APX misunderstands the price mitigation process. Pursuant to the June 19 Order, sellers selling through the ISO are subject to price mitigation. Therefore, when the seller's price is above the proxy price, the seller, not APX, must justify its bid. Furthermore, the seller will invoice the ISO directly for emissions costs for transactions scheduled through the

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[201] See, e.g., Request for Clarification of Duke.

[202] See, e.g., Requests for Clarification of Duke and Reliant.

[203] June 19 Order at 62,562.

[204] Id.

ISO pursuant to ISO dispatch instructions. We note that the Commission determined to leave the issue of APX's role in the hearing established in the July 25 Order, including APX's liability, if any, for refunds and APX's obligation, if any, to provide data, to the presiding administrative law judge in the first instance.

ii. July 25 Clarification Order

On rehearing of the July 25 Clarification Order, NCPA states that it is unclear how it is to implement the general guidance that the Commission offered for other parties facing the dilemma of conflicting obligations under the must-offer requirement and their respective Clean Air Act operating permits.[205]

NCPA asserts that neither of the alternatives suggested by the Commission for obtaining an exemption presents a viable option. According to NCPA, the alternative that it submit "an adequate Mirant-style presentation," places a severe and unfair burden on a party because it requires that the party demonstrate that it (1) had signed an agreement with the local air quality district, which would require both the payment of mitigation penalties and the admission that additional operations would violate its permit; and (2) been sued for signing such an agreement. NCPA contends that the other alternative allowed by the Commission, to obtain a declaratory order from an appropriate court, may be unavailable because it is unclear who would be the appropriate defendant or which court would grant such an order. NCPA believes that courts may consider a request for declaratory order to be unripe.

In an informational filing submitted to the Commission on August, 17, 2001, Duke states that two of the six turbines at its Duke Energy Oakland facility have already reached their hourly operating limits; that the entire facility has used 4,400 of its allowable 5,000 hours for the 12 month period ending December 31, 2001; that it has not entered into a Compliance and Mitigation Agreement with the Bay Area Air Quality Management District; and that the Duke Oakland units are distinguishable from the generators addressed in the July 25 clarification order because they are RMR Condition 2

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[205] In that order, the Commission stated:

> If a generator does not want to wait until it is sued to seek an exemption from the must offer requirement, it may instead obtain a declaratory order from an appropriate court finding that compliance with the must offer requirement will result in a violation of its permits. (San Diego Gas & Electric Co., et al., 96 FERC ¶ 61,117 (2001)).

units which operate only when dispatched by the ISO.[206] Duke states that when it exhausts its hourly limits under its permit, continued operation in excess of those limits would be contrary to its RMR Tariff and would also constitute a violation of its permit, which would expose it to civil penalties. Duke states that under those circumstances the conditions for exemption from the must-offer requirement under the July 25 Clarification Order would apply to Duke Energy Oakland.

Commission Response

We continue to believe that it is essential to promote maximization of generator output in California through the must-offer requirement (so long as sellers are being paid). Therefore, we require a generator to provide concrete evidence that it will be in violation of its permit before we will waive that requirement. However, as we observed in the July 25 Clarification Order, the Commission is not the appropriate forum for determining whether entities are in violation of their Clean Air permits. The guidance contained in the July 25 Clarification Order suggests two ways in which generators may satisfy the evidentiary requirement while respecting the jurisdictional limitations that preclude the Commission from engaging in interpretation of Clean Air Act permits. While NCPA argues that courts may not entertain requests for declaratory orders in these circumstances, NCPA's argument is speculative and does not require identification of additional procedures at this time.

Duke's informational filing does not seek a waiver of the must-offer requirement. We will consider such a request if and when one is filed by Duke.

iii. July 25 Order

The July 25 Order permitted generators to recover in full all of the demonstrable emissions costs incurred during the refund period. The order provided that sellers will submit their emissions costs during the refund hearing for subtraction from their respective refund liabilities. We also explained why it would not be appropriate to include these costs in the calculation of the mitigated Market Clearing Prices.

On rehearing of the July 25 Order, suppliers contend that the refund methodology should be revised to include environmental compliance costs (NOx costs and other

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[206] According to Duke, under its RMR Agreement, the ISO may not request and Duke is not obligated to provide service from a unit where it would violate environmental limitations for the unit. We note that our orders are clear in that generators are not required to run if environmental limits will be broken.

environmental mitigation fees) in the calculation of mitigated Market Clearing Prices,[207] or that all such costs, and not just NOx credits, be offset against refund liabilities.[208] The Marketer Group charges that the Commission erred in allowing generators to recover the cost of NOx emission allowances but denying marketers the right to recover their costs for emissions allowances.[209] The Marketer Group asserts that the mitigated reserve deficiency MCP should be set to include recovery of the cost of these allowances. It asserts that the Commission's failure to recognize that marketers purchased power at market prices that included emission credit costs, but imposed reference prices that do not recover these costs, is unjust and unreasonable, and it suggests two possible methods for calculating the marginal cost of emissions credits that should be included in the reference price, one which could be used where emissions credits are traded, and another which could be used where there is no observable market price.

Commission Response

Consistent with the July 25 Order, we clarify that all demonstrable emissions costs, and not just NOx credits, are to be offset against refund liabilities. This includes credits required to comply with SOx emissions restrictions, and "actual and verifiable environmental compliance fees."[210] It does not include capital improvements that may serve to reduce generators' emissions costs, or other fixed costs associated with such improvements, as discussed above.

Reliant faults the order for not including environmental compliance costs in the mitigated reserve deficiency MCP, since they would not be recognized as part of the actual running costs of the marginal unit. For the reasons described in the July 25 Order, the Commission found that doing so would present an insurmountable burden. Parties have not challenged that finding. Reliant's concern is unwarranted because the order allows each generator to recover its environmental compliance costs for the entire refund period; the Commission has provided an alternative method for full recovery of the emissions costs. The costs need not be included in the mitigated reserve deficiency MCP for the generators to recover their costs.

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[207] See, e.g., Request for Rehearing of Reliant.

[208] See, e.g., Requests for Rehearing of Mirant.

[209] See also Requests for Rehearing of Nevada IEC/CC Washington and CAC.

[210] Request for Rehearing of Reliant at 11.

If a marketer believes that the inability to recover emissions costs through the refund methodology is confiscatory, it will have an opportunity to offer evidence that its revenues were less than its costs after the conclusion of the refund hearing, as discussed above.[211]

We do not believe either of the Marketer Group's proposals for recovery of emissions costs by marketers is workable because they are not verifiable, especially on a portfolio basis. Both proposals suffer from the same flaw that led the Commission to exclude emission costs from the Proxy Price: there is no certainty that the expense was incurred for the power purchased.

d. O&M Adder

The ISO, City of San Diego, and Southern California Water Company seek rehearing of the Commission's decision in the June 19 Order to increase the adder for operation and maintenance expenses from $2.00 to $6.00 per MWh. They claim that this increase is unsupported by evidence of actual costs, that it improperly subsidizes more efficient generation facilities, and that the $2.00 per MWh rate specified in the April 26 Order is more consistent with actual data. In addition, the ISO asserts that the Commission's justification was based on a five-year old analysis and lacks a detailed analysis of the relevancy of the dated DOE data to the current California fleet of generators.

The ISO states that the average O&M costs for 41 current or former RMR units in California, representing over 10,000 MW of in-state gas-fired generating capacity, is $1.5527/MWh, as agreed to in the RMR global settlement.[212]

On rehearing of the July 25 Order, parties again object to the $6.00 per MWh adder. San Francisco opposes any O&M adder, asserting that operation and maintenance expenses are generally treated as fixed costs. If any adder is used, San Francisco and California Parties prefer examination of actual, historical data, or adoption of a $2.00 per MWh adder that may be increased if justified based on the costs of the least efficient unit. PG&E argues that the Commission has not supported the higher figure, and the ISO states that six dollars is almost certainly substantially higher than sellers' actual O&M costs; they both support a $2.00 adder.

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[211]See id.

[212]The ISO points out that five older low-capacity units had average O&M costs over $30.00/MWh, but that these units run infrequently and the number of MWh over which the O&M costs were spread was small.

Commission Response

In the June 19 Order, the Commission found the California market primarily consists of older oil and gas-fired steam plants, which justifies using a long-term average of actual O&M expenses for the same kind of units currently in California. Based on a study conducted by the EIA,[213] the Commission found that a $6 adder for O&M expenses is appropriate. We do not believe that the O&M costs for RMR generators suggested by the California ISO is representative of O&M costs that should be allowed for purposes of the mitigated price allowance. The marginal unit from which the mitigated reserve deficiency MCP is determined is likely to be one of California's older generators, which would incur higher O&M costs. It is appropriate to average costs over a longer time period to obtain a more reliable average of costs for these older units. Furthermore, these generators have been required to run at extraordinary levels, which significantly increases their O&M costs. Based on these considerations, we believe that the Commission properly exercised its discretion in increasing the O&M adder to $6.00. We also disagree that the increased O&M adder improperly subsidizes more efficient generators. Since it is based on average actual O&M costs, it will compensate generators based on a reasonable estimate of costs and will encourage investment in more efficient generation units. These conclusions are equally applicable to the refund period.

We disagree with San Francisco that O&M costs should be treated as fixed costs. In our orders, the Commission sought to approximate the costs of the least efficient marginal unit dispatched in order to emulate the workings of a competitive market.[214] Thus, the inclusion of variable O&M expenses is consistent with the variable costs that would be incurred in a competitive market and, thus, the inclusion of these costs in the refund methodology is appropriate.

e. Creditworthiness Adder

i. June 19 Order

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[213]See http://www.eia.doe.gov/oiaf/issues/opctbl3.html. Oil and Gas Steam Plant Operations and Maintenance Costs, 1981-1987.

[214]We also note that, in the context of cost-of-service pricing, O&M expenses such as fuel and maintenance costs are treated as variable costs. See, e.g., Illinois Power Company, 15 FERC ¶ 61,050, reh'g denied, 17 FERC ¶ 61,063, reh'g granted in part, 19 FERC ¶ 61,073 (1981).

California Utilities and customers seek rehearing of the 10 percent credit adder,[215] provided in the June 19 Order, arguing that (1) it gives the ISO another vague accounting task that only increases the likelihood that tracking of cost-causation and repayment entitlements will not be accomplished; (2) it makes no sense to use regulatory intervention to single out generators for special cost recovery assistance when ISO customers are already overburdened; (3) the Commission has no basis for acting as collection agent on behalf of power sellers under investigation for excess charges;[216] (4) the credit adder is unjustified and unfairly raises the prices ultimately paid by electric consumers in California;[217] (5) the credit adder should not apply to entities that are neither slow to pay nor credit risks;[218] and (6) the credit adder does not adequately address the creditworthiness problems faced by California market participants.[219]

Attorney General of Nevada, Pinnacle West, Portland General, and Idaho Power also seek rehearing of the June 19 Order, contending that the credit adder could encourage sellers to choose the California market over other parts of the WSCC, and potentially interfere with reliability and supply in other WSCC markets if it is not applied to all sales in the WSCC.

Duke claims on rehearing of the June 19 Order that the Commission failed to justify limiting the credit premium to 10 percent.[220] Idacorp contends that if the Commission orders refunds that reflect an inadequate recognition of credit risk, most sellers will be driven away from the California market. Idacorp also states that any adder to compensate for credit impact should reflect actual conditions at the time of the sale,

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[215] See, e.g., Requests for Rehearing of DWR, Oversight Board, ISO, City of San Diego, City of Vernon, Metropolitan, NCPA, PG&E, SDG&E, Sierra Pacific Power and Nevada Power, and Southern California Water Company.

[216] See, e.g., Request for Rehearing of DWR.

[217] See, e.g., Request for Rehearing of City of San Diego and Southern California Water Company.

[218] See, e.g., Request for Rehearing of City of Vernon.

[219] See, e.g., Request for Rehearing of NCPA.

[220] See also Request for Rehearing of Williams, which states that given the extraordinarily high risk of doing business in California, 25 percent is a more commercially reasonable credit premium.

and is thus an issue of fact for hearing. Idacorp also recommends that the Commission allow cost-justifying sellers to include a profit margin that adequately reflects risk.

Reliant requests clarification of the June 19 Order that the mitigated Market Clearing Prices, for purposes of determining which bids must be justified, are to be calculated inclusive of the 10 percent credit adder.

Allegheny Energy requests clarification of the June 19 Order that the 10 percent adder applies to transactions conducted with and settled by the ISO.[221] Parties also request clarification of the conditions under which the Commission will no longer require the imposition of the 10 percent creditworthiness adder;[222] and that the 10 percent adder for credit risk is applicable for all power sellers in the California markets, whether the sales are made by generators or by wholesale power marketers.[223]

Commission Response

In the June 19 Order, the Commission instituted the 10 percent adder to recognize both the larger risk of nonpayment in California when compared with that in the larger West-Wide market, and the longer payment lag in the ISO spot markets when compared with that in the Western bilateral spot markets.[224] The Commission also pointed out that questionable business practices have sent negative signals to future supplies, credit rating agencies, and investors. The Commission has considered arguments that ISO customers are already over burdened and that it is unfair to apply a creditworthiness adder to entities that are not credit risks. However, despite our repeated instructions to the ISO to ensure that there is a creditworthy party backing up each and every transaction, we have continued to receive complaints that suppliers are not being paid. Under these circumstances, we continue to believe that the circumstances that justified institution of a creditworthiness adder have not abated. Until the risk of nonpayment by purchasers in California has been relieved, the adder is still justified. Accordingly, we will deny rehearing.

We will deny requests by generators to increase the level of the creditworthiness adder. Given the fact that generators will earn interest on amounts eventually paid, we

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[221]Request for Clarification of Allegheny Energy.

[222]Request for Clarification of APX.

[223]Request for Clarification of BP Energy.

[224]June 19 Order at 62,564.

believe that 10 percent is reasonable for the risk of certain amounts ultimately not being repaid at all.

We clarify that the mitigated Market Clearing Prices should not include the 10 percent creditworthiness adder, since these prices are applicable to all spot market sales in the WSCC, and the adder applies only within California. As explained in the June 19 Order, the Commission instructed the ISO to add 10 percent to the market clearing price paid to generators for all prospective sales in its markets to reflect credit uncertainty. Furthermore, generators whose bids above the mitigated price are accepted should not include the ten percent adder in their justification filings. As the Commission instructed in the June 19 Order, the ISO must add 10 percent to the price for all prospective sales. Therefore, generators who bid above the proxy price, will be paid their bid price, which is subject to justification and refund, plus a surcharge of 10 percent of their bid price. The adder is not a part of the bid that is to be justified.

We agree with Allegheny Energy that the 10 percent adder applies to transactions conducted with and settled by the ISO. We also confirm that the adder applies to all power sellers in the ISO markets, whether the sales are made by generators or by power marketers. Since the risk of nonpayment by purchasers is felt by all sellers, regardless of their source of supply, all power sellers in California markets are eligible to receive the adder.

The Commission is considering in separate proceedings other issues related to the ISO's obligation to ensure that a creditworthy party backs every transaction, and with contentions that even when dealing with a creditworthy party, sellers still have not been paid. The Commission addressed these issues in a separate order issued on November 7, 2001.[225]

ii. July 25 Order

Similar arguments emerge on rehearing of the July 25 Order. Several entities note that as of January 17, 2001, DWR was the purchaser of record, and, as an arm of the state, was a creditworthy buyer,[226] and they assert that SDG&E remained creditworthy at

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[225] See California Independent System Operator Corporation, 97 FERC ¶ 61,151 (2001) (addressing the ISO's proposed Tariff Amendment No. 40, Docket No. ER01-3013-000, and Motion of Indicated Generators filed in Docket No. ER01-889-008) (November Creditworthiness Order).

[226] See, e.g., Requests for Rehearing of San Francisco, Oversight Board, ISO.

all times.[227] They contend that application of such an adder to past periods bestows a windfall on sellers for no valid reason because its logic does not apply to transactions that have already occurred. California Parties and the ISO also contend that application of a creditworthiness adder and interest for the same transactions is redundant.

Suppliers, on the other hand, believe that the adder should be higher than 10 percent, more in line with common business practices.[228] They note the failure of the ISO and PX to pay for sales prior to January 5, 2001, and that the risk of default by SoCal Edison and PG&E preceded that date, arguing that the adder should apply to transactions prior to that date.

Commission Response

For the same reasons discussed in the context of prospective transactions, we will retain the creditworthiness adder for the refund period, and we will continue to add 10 percent rather than a higher amount. While the knowledge now that an adder will be available for a past period cannot affect the behavior of sellers for that period, we still believe that the adder should be retained. Beginning as of January 5, 2001, sellers bid into the ISO and PX markets with the certainty that a significant risk of non-payment existed. It was reasonable for these sellers to add a premium to their bids because of the risk. We are not willing at this time to require sellers to refund amounts that were reasonably included in their bidding strategies (although we are limiting the level of the premium to an amount we find is reasonable, i.e., 10 percent).

We recognize that some risk of non-payment may have existed prior to January 5; however, the extent and inception of the risk is unclear. There is no doubt about the importance of PG&E's and SoCal Edison's bonds being downgraded, and their losing the credit status required by the ISO's Tariff, both of which occurred on or about January 5. Therefore, it is appropriate that events of January 5, 2001 should trigger the commencement of the creditworthiness adder.

The fact that SDG&E has been creditworthy is not relevant because sellers transacting in the ISO's Imbalance Energy market receive payment from the ISO, regardless of the purchaser, and the ISO has not paid sellers for many months. The same is true for DWR.

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[227] See, e.g., Requests for Rehearing of San Diego, Oversight Board, ISO.

[228] See, e.g., Requests for Rehearing of Dynegy, Duke, Pinnacle West, Puget/Avista.

We disagree that receiving interest on amounts past due negates the need for a creditworthiness adder. Interest assures that parties receive the time value of the money they are owed. The adder offers financial security for the risk of transacting in California markets and not selling in other markets that is warranted in these circumstances.

f. Opportunity Costs, Scarcity Rents, Recovery of Fixed Costs and Justification of Higher Prices

i. June 19 Order

A number of generators argue on rehearing of the June 19 Order that the Commission erred in failing to allow suppliers to include various cost items in their price justification filings.[229] For example, Duke contends that the Commission has failed to demonstrate that its methodology, which omits opportunity costs, fixed costs, replacement costs, scarcity rent and other factors, represents a realistic competitive market outcome. Duke contends that suppliers should be permitted to make individualized showings of opportunity costs associated with environmental restrictions and to permit such demonstrated costs to be flowed through the administrative charge. Mirant argues that the Commission's refusal to allow suppliers to justify a price based on the cost of purchased power lacks any reasoned basis. Mirant recommends that the Commission allow marketers and other sellers to justify prices above the cap based on the cost of purchased power, subject to the Commission's oversight for potential affiliate abuse. LSEs also contend on rehearing that the Commission erred in denying the right to seek recovery of purchased power costs, arguing that the restriction is an unjustified departure from precedent approving rates based on purchased power costs, and would impermissibly require LSEs to offer excess energy for sale at non-compensatory prices.[230]

Other generators contend that the Commission should allow sellers to include in their justification filings amounts to allow recovery of: credit premiums from buyers outside of California having insufficient credit;[231] major expenditures that may be required to keep a generating unit in the market or to maintain a unit in compliance with

[229] See, e.g., Requests for Rehearing of Duke, Dynegy, Enron, Mirant, PPL, Reliant, and PSColorado.

[230] See, e.g., Requests for Rehearing of Pinnacle West, Portland General, PSNM, Salt River, Avista Utilities, and Tucson.

[231] See, e.g., Request for Rehearing of PPL.

environmental standards;[232] and start-up costs other than start-up fuel costs (such as the significant O&M costs that are involved with frequent requests to turn on older generators for short periods of time).[233]

Load serving entities claim on rehearing of the June 19 Order that treating them as marketers and precluding recovery of their purchased power costs fails to recognize the special native load service obligations of load serving utilities.[234] They argue that excluding such costs is an unjustified departure from precedent approving rates based on purchased power costs, and would impermissibly require LSEs to offer excess energy for sale at non-compensatory prices. They also argue that allowing inclusion of purchased power costs is consistent with encouraging forward contracts.

Salt River and PSNM request clarification that LSEs may justify sales above the mitigated Market Clearing Prices based on their cost of purchased power. Tucson argues that the Commission should allow load serving entities to settle spot market sales at prices above the mitigation cap level if justified based on long-term forward purchases that the load serving entity entered into prior to the issuance of the June 19 Order.

On the other hand, on rehearing of the June 19 Order, the Oversight Board opposes justification filings altogether, contending that permitting suppliers to justify each transaction above the mitigated price allows suppliers to manipulate their purported costs, and fails to ensure that wholesale electric prices are just and reasonable. PG&E states that the Commission should clarify its approach for evaluating individual seller justifications for pricing above the mitigated price cap to prevent gaming in fuel pricing (such as by matching highest cost gas with highest cost generation, rather than by justifying pricing based on the entire generation and fuel portfolio).

Dynegy claims on rehearing that it is impossible for generators to provide a complete cost justification, including a detailed breakdown of all of the component costs, within seven days of the end of the month. According to Dynegy, it does not receive a preliminary settlement statement from the ISO until 38 days after the end of the month. Dynegy also states that natural gas costs are not received until five days after the end of the month, leaving only two days to provide a breakdown on a portfolio basis.

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[232]See, e.g., Request for Rehearing of Reliant.

[233]See, e.g., Request for Rehearing of Tri-State.

[234]See, e.g., Requests for Rehearing of Pinnacle West, Portland General, PSNM, Salt River, Avista Utilities, Washington Utilities and Transportation Board and Tucson.

Therefore, Dynegy requests that the Commission adopt a longer timetable based on these considerations.

Commission Response

We decline to allow the additional cost items proposed by parties. As discussed in our prior orders, our mitigation plan is intended to replicate the price that would be paid in a competitive market, in which sellers have the incentive to bid their marginal costs. The mitigated reserve deficiency MCP is then based on a single price which is set by the marginal cost of the last unit produced, and all more efficient units receive the same price, which creates an incentive for firms to increase their efficiency.[235] Furthermore, opportunity costs are not appropriate because energy that is available in real time cannot be sold elsewhere.[236] We note that, during the latter half of this year, spot market sales in all of the major western trading hubs (Palo Verde, Mid Columbia and California-Oregon Border) have consistently been below \$40/MWh, which is well below the current mitigated non-reserve deficiency MCP of approximately \$92/MWh. To the extent generators find that the Proxy Price will not compensate them for their marginal costs, they are permitted to file cost based rates for their entire portfolio in the WSCC.

The Commission determined in the June 19 Order that marketers and load serving entities that choose to participate in real time spot markets must be price takers, because the Commission is unable to trace transactions that can span multiple entities back to the individual generators that supply these transactions. Furthermore, as we have discussed earlier in this order, as price takers, these entities must bid zero. We note that marketers are not subject to the must-offer requirement, and therefore need not bid if they believe that they will under recover their purchased power costs.

We deny requests to allow sellers to include in their justification filings amounts to allow recovery of credit premiums from buyers outside of California having insufficient credit. No party has indicated that there are non-creditworthy purchasers outside of California. Furthermore, in the bilateral market outside of California parties can and typically do include in their contracts appropriate contract provisions to ensure that they are dealing with a creditworthy party.

We decline to allow sellers to include in the justification filings environmental and start up costs. In the June 19 Order, the Commission allowed generators in California to invoice the ISO for their emissions and start-up fuel costs. Sellers will

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[235] June 19 Order at 62,560.

[236] Id. at 62,564.

receive these costs over and above the mitigated Market Clearing Prices. Therefore, these are not to be included. Similarly, start-up costs other than start-up fuel costs (such as the significant O&M costs that are involved with frequent requests to turn on older generators for short periods of time), should not be included. In the order on the ISO's compliance filings being issued concurrently with this order, we are requiring the ISO to compensate generators for start up and minimum load costs, to compensate generators for their actual costs during each hour that generators are not scheduled to run under a bilateral agreement, are not on a planned or forced outage, and are running in compliance with the must-offer obligation, but are not dispatched by the ISO. We also will not allow generators to include major expenditures that may be required to keep a generating unit in the market or to maintain a unit in compliance with environmental standards. Capital investment for pollution control equipment will increase the hours that a plant can operate which will increase the revenues from the Imbalance Energy market for the potential recovery of such costs. The proposed recovery of capital costs as a separate adder as is allowed for emissions costs is inappropriate because such investments are not subject to the volatility and changing circumstances as are present with the California emissions programs. Capital cost recovery would be appropriate in the context of cost-based rates. As we stated in the June 19 Order, sellers who desire cost-based rates may do so for their entire portfolio of resources.

We will not allow LSEs to justify sales above the mitigated Market Clearing Prices based on their cost of purchased power. Like marketers, LSEs purchase from many sources of supply, and it is in most instances not possible to trace the power to a particular generator. Furthermore, we note that LSEs purchase power in order to serve their native load obligations. To the extent that they have excess capacity to sell, the proceeds of such sales would reduce the sunk costs of that power that their customers otherwise would pay.

Mirant and Duke contend that the ISO should play no part in reviewing or gathering the bid justification data. We note that this was an issue that should have been, but was not, raised on rehearing of the April 26 Order in which we required submission of justification data to the ISO. Because the Commission did not reverse its findings on this issue in the June 19 Order, Mirant and Duke's contention is untimely.

We reject as untimely Dynegy's request for rehearing of the requirement to submit complete justification filings within seven days of the end of the month. In the April 26 Order, the Commission required that "[a]t the end of each month in which a generator submits a bid higher than the market clearing price, the generator must file with the Commission and the ISO, within seven days of the end of the month, its complete justification, including a detailed breakdown of all of its component costs for each transaction exceeding the market clearing price established by the proxy bid." Since the

June 19 Order restated, but did not alter, this requirement, Dynegy's request for rehearing after the June 19 order is untimely.

ii. July 25 Order

Suppliers raise most of these same issues and arguments on rehearing of the July 25 Order, pressing for the opportunity to justify prices above the mitigated Market Clearing Prices based on these additional factors, the ability to offset the costs against potential refunds, or their outright inclusion in the mitigated Market Clearing Prices.[237] In particular, they object to the prohibition on offsetting purchased power costs against potential refunds. BP notes that the Commission's rationale from the July 25 Order, that the purchased power costs of public utilities were sunk costs, does not apply to unaffiliated power marketers, which have no sunk costs. BP and others respond to the Commission's statement that they are not guaranteed recovery, just the opportunity to recover their costs, by explaining that marketers will have no opportunity to recover these costs under the retroactively imposed refund methodology. Portland General argues this is unlawful without a finding of market power or other abuse. Others explain that they had no ability to avoid purchasing and reselling high-cost power, and claim that the Commission's position results in a confiscatory rate.[238] Dynegy seeks clarification whether start-up fuel costs are recoverable in the same manner as in the June 19 Order.

Several suppliers call the Commission's departure from policy developed in orders prior to the July 25 Order arbitrary and capricious, particularly when utilization of bilateral forward contracts (prices for which they now seek to use as justification to exceed the mitigated Market Clearing Prices) had been encouraged in those orders. PSNM refers to specific assurances by the Commission concerning the use of purchased power costs as justification for sales prices above the mitigated prices, as well as a passage in the November 1 Order implying that sellers' refund liability would be limited "to no lower than the sellers' marginal costs or legitimate and verifiable opportunity

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[237]See, e.g., Request for Rehearing of Marketer Group, calling the Commission's decision to disregard marketers' costs confiscatory (at 25-27); Nevada IEC/CC Washington, warning that the methodology will discourage new generation and asserting that denying full compensation to suppliers constitutes an unconstitutional taking; LADWP, seeking recovery of transmission losses, embedded costs, and interest on debt; and Dynegy, arguing that scarcity rents and opportunity costs (at 4-7) and all elements of short-run marginal costs, such as intrastate gas transportation costs and certain ISO charges (at 11-13), should be included in the Proxy Price.

[238]See, e.g., Requests for Rehearing of Pinnacle West, PSNM, PSColorado.

costs,"[239] and asserts that it relied to its detriment on these statements. PSColorado cites Commission cases dealing with pricing structures for "off-system" sales and charges that the Commission made no findings that would support departing from them.[240]

LSEs contend that their unique circumstances (i.e., they must stand ready to serve peak native loads, and are expected to sell their more expensive surplus power on the wholesale market to help reduce cost of service to native load) warrant different treatment.[241] Nevada BCP seeks a specific exemption for LSEs that it represents from paying any refunds.

Several utilities outside of California claim that any refunds required to be paid will have to be passed on to their ratepayers, resulting in subsidization of California ratepayers.[242] Portland General contends that any such cost-shifting is per se arbitrary and capricious. Nevada BCP characterizes the situation thus: "California customers are guaranteed the mitigated price while utilities that incurred purchased power costs that, in most cases, if not all, are above the mitigated price, are left to subsidize mitigated prices for California purchasers."[243]

Dynegy and Mirant object to the Commission's invitation to submit cost-of-service rates for each generator's entire portfolio of units, noting that each of its affiliated subsidiaries are separate limited liability companies, and arguing that each should be entitled to file cost-based rates regardless of the others' decision to do so. AEPCO asserts that it would be inappropriate to force cooperatives to incur the substantial administrative burden associated with making such a cost-of service filing with the Commission.

Commission Response

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[239]Request for Rehearing of PSNM at 57, quoting November 1 Order, 93 FERC at 61,370.

[240]See, e.g., Request for Rehearing of PSColorado at 10-11, citing Illinois Power Company, 57 FERC ¶ 61,213 (1991); Detroit Edison Company, 78 FERC ¶ 61,149 (1997).

[241]See, e.g., Requests for Rehearing of Puget/Avista, Portland General, PSNM.

[242]See, e.g., Requests for Rehearing of Portland General, Nevada BCP, PSColorado.

[243]Request for Rehearing of Nevada BCP at 10.

For the reasons discussed above, we will not allow any additional cost items to be included in the refund formula. To hold otherwise would be inconsistent with our marginal cost based approach. We recognize, however, that market participants were not basing their buying and selling decisions with specific knowledge of the mitigated Market Clearing Prices during the refund period, and that they may not have an opportunity to recover their costs (once refunds are ordered) because the refund methodology is being imposed retroactively. Therefore, as discussed elsewhere in this order, we will provide an opportunity after the conclusion of the refund hearing for marketers, those reselling purchased power, or those selling hydroelectric power to submit evidence that the impact of the refund methodology on their overall revenues over the refund period is inadequate. Such demonstrations must show the impact on all transactions from all sources during the refund period.

We do not agree that LSEs' circumstances warrant different treatment. As explained above, to the extent LSEs have excess capacity to sell, the proceeds of those sales serve to reduce the sunk costs of the purchased power costs their customers otherwise would pay. No other sellers are exempt from potential refunds for sales into the ISO and PX spot markets, and Nevada BCP has not justified such an exemption for LSEs. Nevertheless, as discussed elsewhere in this order, sellers, including LSEs, will have an opportunity to demonstrate that the refund methodology results in a total revenue shortfall (or, for marketers, imposes costs in excess of revenues) for all jurisdictional transactions over the duration of the refund period. We will continue to prohibit recovery of opportunity costs, as the Commission has indicated will be our approach since the December 15 Order.[244] We will also prohibit recovery of major expenditures associated with plant additions, since these should be capitalized, as discussed above. Parties' purported reliance on prior orders as to the recovery of purchased power costs was misplaced; neither the November 1 Order, December 15 Order, nor March 9 Order proposed or provided that such costs could be used to justify sales prices above the mitigated prices.

We are not persuaded that California ratepayers are being subsidized at the expense of ratepayers elsewhere in the West. California ratepayers have been exposed to some of the highest wholesale power prices anywhere, particularly before January 1, 2001, when California IOUs had been required to purchase all of their power in the spot markets. The Commission had to intervene and fix the excessive prices being charged in those markets. In any event, concerns about subsidization cannot justify the continuation of excessive rates.

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[244]December 15 Order at 62,010.